NON-PUBLIC?: N
ACCESSION #: 9601110156
LICENSEE EVENT REPORT (LER)

FACILITY NAME: COMANCHE PEAK STEAM ELECTRIC STATION PAGE: 1 OF 6
UNIT 2

DOCKET NUMBER: 05000446

TITLE: ESF ACTUATION INITIATED DUE TO A FAILURE OF MAIN FEEDWATER PUMP SPEED CONTROLLER
EVENT DATE: 12/05/95 LER #: 95-004-00 REPORT DATE: 01/02/96

OTHER FACILITIES INVOLVED: CPSES UNIT 1 DOCKET NO: 05000445

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: RAFAEL FLORES - SYSTEM ENGINEERING TELEPHONE: (817) 897-5590
MANAGER

COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE NPRDS: N

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On December 5, 1995, at approximately 1:11 p.m. Comanche Peak Steam Electric Station Unit 2 experienced a reactor trip initiated due to Lo Lo Steam Generator(SG) reactor trip signal. Prior to the event, troubleshooting on Main Feedwater Pump(MFP) 2A speed control mechanism was being performed. The speed control mechanism was believed to have failed. During the troubleshooting of the speed controller, the MFP 2A turbine control valve began to cycle open and shut repeatedly. In accordance with previously discussed contingency actions, operators manually tripped the MFP 2A. The plant ran back from 100 percent to 60 percent power automatically as expected. Approximately I minute after the runback, erratic steam dump operation resulted in excessive shrink of all SG levels. The unit automatically tripped due to Lo Lo level in SG

3. Additionally, the timer on the pole disagreement for the switch yard breakers resulted in the breakers opening and isolation of the 345Kv switchyard east bus.

The cause of the event was a failure of the MFP 2A controls. The manual trip of the MFP and the rapid closure of the steam dump valves increased the shrinkage in the SGs initiating the actuation of the Lo Lo SG signal which resulted in an automatic reactor trip. The speed control on the MFP 2A and the switchyard breakers have been reworked and modified as required.

END OF ABSTRACT

I. DESCRIPTION OF THE REPORTABLE EVENT

A. REPORTABLE EVENT CLASSIFICATION

An event or condition that resulted in a manual automatic actuation of any Engineered Safety Features (ESF) including the Reactor Protection System (RPS).

B. PLANT OPERATING CONDITIONS PRIOR TO THE EVENT

On December 5, 1995, prior to the event, Comanche Peak Steam Electric Station (CPSES) Unit 2 was in Mode 1, Power Operation, with reactor power at 100 percent.

C. STATUS OF STRUCTURE, SYSTEMS, OR COMPONENTS THAT WERE INOPERABLE AT THE START OF THE EVENT AND THAT CONTRIBUTED TO THE EVENT

There were no inoperable structures, systems or components that contributed to the event.

D. NARRATIVE SUMMARY OF THE EVENT, INCLUDING DATES AND APPROPRIATE TIMES

At approximately 9:00 a.m., on December 5, 1995 Unit 2 plant operators (Utility, Licensed) reported to the System Engineering (Utility, Non-Licensed), that the Main Feedwater Pump (MFP) 2A (EIIS:(P)(SJ)) speed had increased from approximately 4900 rpm to about 5100 rpm and could not be controlled by the General Electric and Westinghouse controllers. Plant operators (OPs) and system engineers (SEs) initiated troubleshooting in an attempt to resolve what was believed be stuck speed control hydraulic valve. A planned power ramp down to resolve the problem would then be initiated. At approximately 1:09 p.m., I&C connected monitoring equipment. However, before any action could be taken, the MFP turbine speed began oscillating uncontrollably from 4900 rpm to 5115 rpm. At 1:10 p.m., in accordance with previously discussed contingency actions OPs manually tripped MFP 2A, which initiated a turbine runback. Steam Generator (SG) (EIIS:(SG)(SB)) levels decreased and the steam dump valves opened to control Reactor Coolant System (EIIS:(AB)) temperature per design. Unexpectedly, the steam dumps closed rapidly from approximately 45 percent to 17 percent demand, causing shrink in the steam generators.

The SG shrink and the existing low SG levels caused a reactor trip on a Lo Lo level in SG 3 at approximately 1:11 p.m., on December 5, 1995. The RPS and the ESF actuated as designed. Auxiliary Feedwater Pumps(EIIS:(P)(BA)) started as expected and a feedwater isolation occurred.

The 7 cycle time delay on the pole disagreement for the switchyard Breaker 8020 (which is the Unit 2 generator output to the east bus) resulted in delay of the breaker opening with resultant isolation of the 345Kv switchyard east bus. This isolation was as designed in the event of a generator output breaker failing to open. Breaker 8020 opened but not before the bus failure sensor sensed the breaker not open and initiated an east bus isolation. The west bus was unaffected.

Following the trip at approximately 1:11 p.m. on December 5, 1995, Control Room personnel (utility, licensed) responded in accordance with plant procedures. Plant systems responded as expected, and the plant was stabilized in Mode 3, Hot Standby.

An event or condition that results in an automatic actuation of any ESF, including the RPS, is reportable within 4 hours pursuant to the requirements of 10CFR50.72(b)(2)(ii).
At 4:04
p.m. on December 5, 1995, the Nuclear Regulatory Commission Operations Center was notified of the event via Emergency Notification System.

E. THE METHOD OF DISCOVERY OF EACH COMPONENT OR SYSTEM FAILURE, OR
PROCEDURAL OR PERSONNEL ERROR

The reactor trip was annunciated by numerous alarms in the Control Room.

II. COMPONENT OR SYSTEM FAILURES

A. FAILURE MODE, MECHANISM, AND EFFECT OF EACH FAILED COMPONENT

The MFP sliding block which provides feedback to the control system caused the speed of the MFP to oscillate and could not be controlled. The MFP was manually tripped which initiated a turbine run back and the SG levels decreased resulting in an automatic trip of the reactor.

B. CAUSE OF EACH COMPONENT OR SYSTEM FAILURE

The failure of the MFP appears to have been caused due to excessive wear in the sliding block which provides feedback to the limit switch control system. The wear on the guide block prevented the block from sliding free on the guide.

C. SYSTEMS OR SECONDARY FUNCTIONS THAT WERE AFFECTED BY FAILURE OF
COMPONENTS WITH MULTIPLE FUNCTIONS

Not applicable - No failures of components with multiple functions have been identified.

D. FAILED COMPONENT INFORMATION

Component Name: MFP High Pressure Control Valve
Part Name: Guide Block
Part No.: 134B195DR

III. ANALYSIS OF THE EVENT

A. SAFETY SYSTEM RESPONSES THAT OCCURRED

Both Motor Driven Auxiliary Feedwater Pumps and the Turbine Driven Auxiliary Feedwater Pumps started as expected.

B. DURATION OF SAFETY SYSTEM TRAIN INOPERABILITY

No safety system trains were inoperable during this transient.

C. SAFETY CONSEQUENCES AND IMPLICATIONS OF THE EVENT

A loss of normal feedwater resulting from pump failure, valve malfunction, or loss of offsite power leads to a reduction in the capability of the secondary system to remove heat generated in the reactor core. These events are analyzed in section 15.2.7 of the CPSES Final Safety Analysis Report (FSAR) which used conservative assumptions in the analysis to minimize the energy removal capability of the Auxiliary Feedwater system.

The loss of 345 Kv (preferred offsite power supply) along with one unit tripping at full power and a design bases accident occurring on the other unit has been analyzed in CPSES FSAR section 8.2 and 8.3. Since there was no loss of prefered offsite power experienced during the December 5, 1995 event, the conservative assumption in FSAR section 8.2 and 8.3 were deemed to bound the event.

Based on the above, it was concluded that the event had no impact on the health and safety of the public.

IV. CAUSE OF THE EVENT

The cause of the event was deemed to be excessive wear in the sliding block which provides position feedback to the limit control system.

The steam dumps were placed in the steam pressure mode of operation and they appeared to work properly in that mode of operation. TU Electric believes that the erratic operation of the steam dumps was initiated by a fault in the controller card(s), which may have been induced due to the aging of the card(s).

V. CORRECTIVE ACTIONS

The MFP controller has been reworked/repaired. The electronic cards for the steam dumps have been reworked/replaced (as required). The affected equipment was tested and declared functional prior to startup of CPSES Unit 2.

Additionally, TU Electric management has initiated a Task Team. The Task Team has been chartered to evaluate the root/contributing causes of the November 19, 1995 (ref. LER 445/95-007-00) and the December 5, 1995 events, and to provide recommendations for corrective actions.

VI. PREVIOUS SIMILAR EVENTS

There have been previous events which involved failure of the Feedwater Pumps. However, the causes of these events were sufficiently different, such that the corrective actions for the previous events may not have prevented the December 5, 1995 event.

VII. ADDITIONAL INFORMATION

All times provided are approximated and are Central Standard Time.

East Bus 345Kv experienced a lockout similar to a lockout which occurred during a Unit 1 reactor trip on November 19 (See TU Electric LER 445/95-007-00). Both the November 19 Unit 1 and December 5, 1995 Unit 2 trips experienced a loss of one half of Switchyard Buses 345Kv. TU Electric found that the result of the loss of one bus in each trip was due to switchyard breaker pole disagreement. Switch yard breaker pole disagreement protective relaying is designed to initiate when one pole of a breaker is in a different state e.g., one pole open while the other two are closed. Following a seven cycle delay (approximately 116 milliseconds), the protective relaying deenergizes one of two switchyard busses by opening all of its supply breakers in an effort to isolate the perceived fault. As a result, the opposite unit breaker supplying that switchyard bus is designed to open, as it did in both trips.
TU Electric implemented a task team to investigate the cause of these failures and performed cleaning and lubrication of the two Unit 2 main transformer breakers. Following maintenance on the two Unit 2 main transformer breakers, TU Electric engineering performed pole timing tests to verify that they were set properly, and the electrical lineup was restored to normal.

As stated in TU Electric LER 445/95-007-00, "A!ll pole disagreement timers have been removed/isolated from all the switchyard ITE breakers." The removal or isolation of the pole disagreement timers will prevent the buses from tripping from bus backup timers for this type of event. However, the breakers will perform their intended

function as required. TU Electric believes that this action, and
development of a preventive maintenance program for the breaker
operating mechanisms will prevent recurrence of the switchyard bus
isolations.

ATTACHMENT TO 9601110156 PAGE 1 OF 1

Log # TXX-95324
File # 10200
TUELECTRIC Ref.
#10CFR50.73(a)(2)(iv)

C. Lance Terry
Group Vice President January 2, 1996

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES) UNIT 2
DOCKET NO. 50-446
MANUAL OR AUTOMATIC ACTUATION OF ENGINEERED SAFETY
FEATURE(ESF)
LICENSEE EVENT REPORT 446/95-004-00

Gentlemen:

Enclosed is Licensee Event Report (LER) 95-004-00 for Comanche Peak Steam
Electric Station Unit 2, "ESF Actuation Initiated Due to a Failure of
Main Feedwater Pump Speed Controller."

Sincerely,

C. L. Terry

OB: ob
Enclosure

cc: Mr. L. J. Callan, Region IV
Mr. W. D. Johnson, Region IV
Resident Inspectors, CPSES

P. O. Box 1002 Glen Rose, Texas 76043

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